BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA
DOCKET NO. 2019-182-E

In the Matter of:	)
South Carolina Energy Freedom Act	)
(H.3659) Proceeding Initiated Pursuant to	)
S.C. Code Ann. Section 58-40-20(C):	)
Generic Docket to (1) Investigate and	)
Determine the Costs and Benefits of the	)
Current Net Energy Metering Program	)
and (2) Establish a Methodology for	)
Calculating the Value of the Energy	)
Produced by Customer-Generators	)

DIRECT TESTIMONY OF JUSTIN R. BARNES ON BEHALF OF SOLAR ENERGY INDUSTRIES ASSOCIATION AND NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A. My names is Justin R. Barnes. My business address is 1155 Kildaire Farm Rd., Suite 202, Cary, North Carolina, 27511. My current position is Director of Research with EQ Research LLC.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am submitting testimony on behalf of the Solar Energy Industries Association ("SEIA") and the North Carolina Sustainable Energy Association ("NCSEA").

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE SOUTH CAROLINA PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. Yes. I submitted testimony on behalf of The Alliance for Solar Choice in Commission Docket No. 2014-246-E addressing the implementation of 2014 Public Act 236, and in Docket Nos. 2015-53-E, 2015-54-E, and 2015-55-E addressing the applications of the state's three investor-owned utilities ("IOUs") to establish distributed energy resource ("DER") programs pursuant to Public Act 246. I also submitted testimony on behalf of Vote Solar in Docket Nos. 2018-318-E and 2018-319-E, which addressed the Duke Energy affiliates' most recent South Carolina rate case applications.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND OCCUPATIONAL BACKGROUND.

A. I obtained a Bachelor of Science in Geography from the University of Oklahoma in Norman in 2003 and a Master of Science in Environmental Policy from Michigan Technological University in 2006. I was employed at the North Carolina Solar Center at N.C. State University for more than five years as a Policy Analyst and Senior Policy Analyst.[1] During that time I worked on the *Database of State Incentives for Renewables and Efficiency ("DSIRE")* project, and several other projects related to state renewable energy and energy efficiency policy. I joined EQ Research in 2013 as a Senior Analyst and became the Director of Research in 2015. In my current position, I coordinate and contribute to EQ Research's various research projects for clients, assist in the oversight of EQ Research's electric industry regulatory and general rate case tracking services, and perform customized research and analyses to fulfill client requests.

Q. PLEASE SUMMARIZE YOUR RELEVANT EXPERIENCE AS RELATES TO THIS PROCEEDING.

A. My professional career has been spent researching and analyzing numerous aspects of federal and state energy policy, spanning more than a decade. Throughout that time, I have reviewed and evaluated trends in regulatory policy, including trends in DER policy, rate design and cost of service. For example, I have closely followed

[1] The North Carolina Solar Center is now known as the North Carolina Clean Energy Technology Center.

the progression of regulators' interest and investigations of DER costs and benefits and cost of service and resulting determinations for the better part of the last decade.

Outside of South Carolina I have submitted testimony before utility regulatory commissions in Colorado, Georgia, Hawaii, Kentucky, New Hampshire, New Jersey, New York, North Carolina, Oklahoma, Texas, and Utah, as well as to the City Council of New Orleans, on various issues related to DER policy, net metering, rate design, and cost of service.[2] These individual regulatory proceedings have involved a mix of general rate cases and other types of contested cases. My *curriculum vitae* is attached as Exhibit JRB-1. It contains summaries of the subject matter I have addressed in each of these proceedings.

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY AND HOW IT IS ORGANIZED.

A. The purpose of my testimony is to address three sub-topics associated with the Commission's review of the costs and benefits of net metering and distributed generation ("DG"). First, in Section II I discuss the general conceptual framework for net metering and DG cost-benefit analyses and offer recommendations on how the Commission should view and analyze the results of such studies. In Section III I specifically discuss how direct and indirect economic impacts can be viewed and present examples of how regulatory decisions in two other jurisdictions have produced significant disruptions of the rooftop solar industry and accompanying negative economic impacts. In Section IV I discuss of how DG can support greater

[2] The City Council of New Orleans regulates the rates and operations of Entergy New Orleans in a manner equivalent to state utility regulatory commissions.

resiliency and recommend that the Commission's evaluation of net metering and DG costs and benefits include consideration of enhanced resiliency benefits that result from greater DG deployment. Section V contains my concluding remarks.

Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION ON THESE TOPICS AND THE REASONS FOR YOUR RECOMMENDATIONS?

A. On the issue of the general nature of the analysis of costs and benefits, I recommend that the Commission take a broad and forward-looking view when determining the scope of potential benefits to be included in the evaluation of the benefits and costs of net metering. With respect to breadth, the scope of benefits should include all benefits reasonably expected to arise from DG growth even if those benefits are difficult to quantify or have associated uncertainty. These qualitative (or non-quantified) benefits should still be given weight in the assessment of the costs and benefits of net metering. With respect to adopting a forward-looking outlook, the Commission should consider the ways in which new technologies such as on-site energy storage and smart inverters could modify the results of the analysis. Such an outlook is reasonable because the Commission is engaged in an exercise of evaluating future DG rates and rate structures and with proper signals and mechanisms, these new technologies can dramatically enhance DG value.

Second, on the issue of direct and indirect economic impacts, I recommend that the Commission give substantial weight to the potential negative economic impacts of utilizing a narrow scope of benefits to determine DG value and utilizing that value in setting DG rates. Such substantial weight is supported by the express directive in Act 62 that the evaluation of costs and benefits include direct and indirect economic impacts, and statements of legislative intent that speak to avoiding disruption of a growing DG market, and building on the success of Act 236 of 2014.

Finally, with respect to the value of DG in enhancing grid resiliency, I recommend that the Commission at minimum incorporate enhanced grid resiliency as a qualitative benefit if it determines that it cannot be reliably quantified. I urge the Commission to adopt a forward-looking approach to evaluating this future benefit stream, and incorporate the acknowledgement that net metering itself has and will continue to contribute to greater resiliency by supporting the installation of existing DG systems that can later be retrofitted with battery storage. In this respect, I urge the Commission to view the benefits of net metering and DG as they *could be* with the right policies, not just what they have been in the past.

II. DG COST BENEFIT ANALYSES

A. Act 62 analytical Framework

Q. PLEASE BRIEFLY DESCRIBE HOW ACT 62 RELATES ECONOMIC IMPACTS AND JOBS TO THE EVALUATION OF THE COSTS AND BENEFITS OF THE NET METERING PROGRAM AND THE ESTABLISHMENT OF THE SUCCESSOR SOLAR CHOICE METERING TARIFFS.

A. Act 62 requires that when evaluating the benefits and costs of net metering, the Commission shall consider, *inter alia*, "the direct and indirect economic impact of the net energy metering program to the State…". In addition to this provision, the legislative intent of Act 62 further clarifies the resulting Solar Choice Metering Tariff should achieve the following policy goals:

1. [B]uild upon the successful deployment of solar generating capacity through Act 236 of 2014 to continue enabling market-driven, private investment in distributed energy resources across the State by reducing regulatory and administrative burdens to customer installation and utilization of onsite distributed energy resources;
2. [A]void disruption to the growing market for customer-scale distributed energy resources.
3. [R]equire the commission to establish solar choice metering requirements that fairly allocate costs and benefits to eliminate any cost shift or subsidization associated with net metering to the greatest extent practicable.[3]

Q. WHAT RELEVANCE DO THE STATEMENTS OF LEGISLATIVE INTENT HAVE ON THE DEVELOPMENT OF AN ANALYSIS OF THE COSTS AND BENEFITS OF THE NET METERING PROGRAM?

A. The legislative intent statements of Act 62 clarify and amplify the specific directives regarding the economic impact information the Commission must consider in the benefit cost analysis of the current net metering program. Moreover, while legislative intent lists the elimination of any cost shift or subsidization (to the extent it exists at all) to the greatest extent practicable, this goal must be viewed in context with the other policy goals of avoiding disruption to the private DER market

[3] Act 62, Section 5.

and ensuring that the resulting program builds on the success of Act 236 in stimulating private investment and continued growth in customer-sited DERs.

To enact these policy goals, the legislature provided the Commission specific directives for conducting the cost-benefit analysis and include the requirement that the Commission incorporate direct and indirect economic impacts, as well as "any other information the Commission deems relevant." These legislative intent statements and requirements for conducting the benefit cost analysis make clear that the legislature intends the Commission to take a broad and forward-looking view when assessing the benefits of DG.

By "broad" I mean that the Commission can and should consider potential benefits that may be more difficult to quantify than marginal costs or cost of service metrics. By "forward-looking" I mean that the cost benefit evaluation should give consideration to benefits that can be realized through the deployment and use of new technologies, most specifically battery storage and smart inverters. In other words, since the cost-benefit analysis is slated to serve as the foundation for future solar choice metering tariffs, it should give due consideration to identifying potential future benefit streams than can be realized under any successor tariffs that are eventually deployed. I see both characteristics as intrinsically tied to a desire to build upon past successes and avoid disrupting a growing market.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS ABOUT HOW THE STATEMENTS OF LEGISLATIVE INTENT SHOULD INFORM THE COMMISSION'S TREATMENT OF COST-BENEFIT ANALYSIS?

A. Yes. Both argue for consistency with respect to the overarching analytical framework and assumptions under which costs and benefits are evaluated across utilities. It is my understanding that each investor-owned utility ("IOU") will present its own evaluation in the individual tariff dockets. I anticipate that the individual analyses could differ considerably from one another due to differences in the methodological framework and assumptions, as is often the case when such analyses are performed.

Act 62 supports standardization of the utilities' analyses in two ways. First, it seeks to build on Act 236 of 2014, which itself resulted in net metering being established in a standardized way across IOU service territories. Second, it would be disruptive to the market for customer-scale DG to allow cost benefit studies with different analytical frameworks and assumptions to form the basis for successor tariffs in individual utility territories. Differing assessments of costs and benefits could potentially produce dramatically different "solutions" in the form of successor tariffs in different utility territories. Such an outcome would add unnecessary complexity for providers of customer-sited DG, while also creating a potential distortion in the distribution of costs and benefits, including direct and indirect economic benefits.

Q. HOW DO YOU RECOMMEND THAT THE COMMISSION ACHIEVE THE KIND OF "CONSISTENCY" THAT YOU RECOMMEND?

A. The basic methodological framework and assumptions should be made uniform, even if some inputs into analytical modeling may differ from utility to utility. For instance, cost and benefit categories, the cost-effectiveness tests used, and the specific methods used to derive values for costs and benefits should be uniform, whereas it could be reasonable to allow certain inputs (*e.g.*, contribution to peak loads based on the timing of peak loads) to be utility-specific.

B. DG Cost-Benefit Evaluation Efforts

Q. WHAT ROLE HAVE DG COST-BENEFIT STUDIES HISTORICALLY PLAYED IN THE DEVELOPMENT OF STATE DG POLICIES?

A. The impetus to study the costs and benefits of DG has arisen in a variety of different contexts (*e.g.,* legislative mandates, regulatory investigations, self-directed by utilities or other interested parties). While the role that these studies have played in developing DG policy can differ from state to state, in my experience the most common role has been as an informational tool to support future decision-making. In other words, DG cost-benefit analyses are often used to provide policy makers quantitative and qualitative information about existing DG policy (*e.g.*, whether a cross-subsidy exists) and help inform whether some type of policy change is needed, and if so, to help guide the policy process.

Many past studies have approached the question of costs and benefits in an oblique way by focusing largely on the question of solar value and presenting that value in comparison to the residential retail rate.[4] Accordingly the "cost" under this framework is the residential retail rate. The results of such a comparison can serve as the answer to the basic threshold question of whether any further investigation or action may be required.

Q. IS EVALUATING DG COSTS AND BENEFITS THE SAME AS EVALUATING DG CUSTOMER COST OF SERVICE?

A. No. A cost of service analytical framework takes a fundamentally different view of DG than a long-term cost-benefit analysis. The main difference between a cost of service framework and a long-term DG value assessment is that whereas a study of DG value seeks to identify the relationship between DG and long-term marginal costs, a cost of service analysis presents a snapshot in time of DG customer responsibility and payment for embedded costs.

Both approaches can provide useful information, but it is important to appreciate that a cost of service study does not necessarily identify what is in the best interests of ratepayers in the long-term. For instance, the scope of "benefits" considered in a cost of service study is generally narrower than a cost-benefit study or a value of DG study because a cost of service study focuses only on the past and only on costs reflected in the utility system. From the standpoint of a given class of customers (*i.e.* the existence of an intraclass subsidy), the benefit takes the form of reduced allocation of costs to that class due to the presence of DG customers and how that compares to the amounts that DG customers avoid paying. As a

[4] Strictly speaking, DG or solar value studies may exclude the cost side of the cost-benefit equation, though in practice some such solar value studies include consideration of future costs.

consequence, a cost of service study tends to treat some costs (*e.g.,* distribution investments) as fixed even though DG can contribute to longer-term avoidance of these types of costs. Likewise, a cost of service framework typically excludes societal benefits such as economic impacts, and other potential sources of DG value such as avoided future environmental costs (compliance and social) and risk hedging.

Q. IS THE USE CASE FOR A COST OF SERVICE ANALYSIS GENERALLY THE SAME AS FOR A DG COST-BENEFIT ANALYSIS?

A. No. A DG cost of service analysis requires different data than a cost-benefit analysis, including load research on DG customers. Since most utilities do not immediately have this data and collecting it takes time and costs money, a common approach has been to use cost-benefit analysis to identify whether in fact a long-term "subsidy" problem exists as a sort of threshold question. The added complexity of cost of service evaluation is then only pursued if in fact a subsidy is identified to support future ratemaking efforts to mitigate the subsidy. In other words, a cost of service study is only necessary if regulators have good reason to believe that a long-term subsidy exists in a magnitude that requires remedial action. While this type of progression has not necessarily been universally present in regulatory investigations of net metering or DG policies, it does represent the general chronology in many states, and in my view is the most rational approach to such investigations.

Q. HOW DOES A COST OF SERVICE EVALUATION FIT INTO THE COMMISSION'S OBLIGATION TO CONDUCT AN ANALYSIS OF THE COSTS AND BENEFITS OF NET METERING?

A. Act 62 refers to the "cost of service implications of customer-generators on other customers within the same class" as one aspect of the analysis of costs and benefits from a total of four directives. The Commission's evaluation must also consider long-term marginal costs, the value of DERs methodology adopted in Order No. 2015-194, and direct and indirect economic impacts. The Commission may also consider any other factor it deems necessary.[5]

Q. WHAT IS THE RISK OF FOCUSING ONLY ON SHORT-TERM MEASURES OF VALUE WHEN CONSIDERING THE COSTS AND BENEFITS OF DG AND NET METERING?

A. Focusing only on the short-term with respect to DG costs and benefits can produce sub-optimal decisions from a long-term perspective. In the specific case of DG cost-benefit evaluations, a short-term focus may lead to policy changes that stymie DG growth which then prevents long-term benefits from being realized.

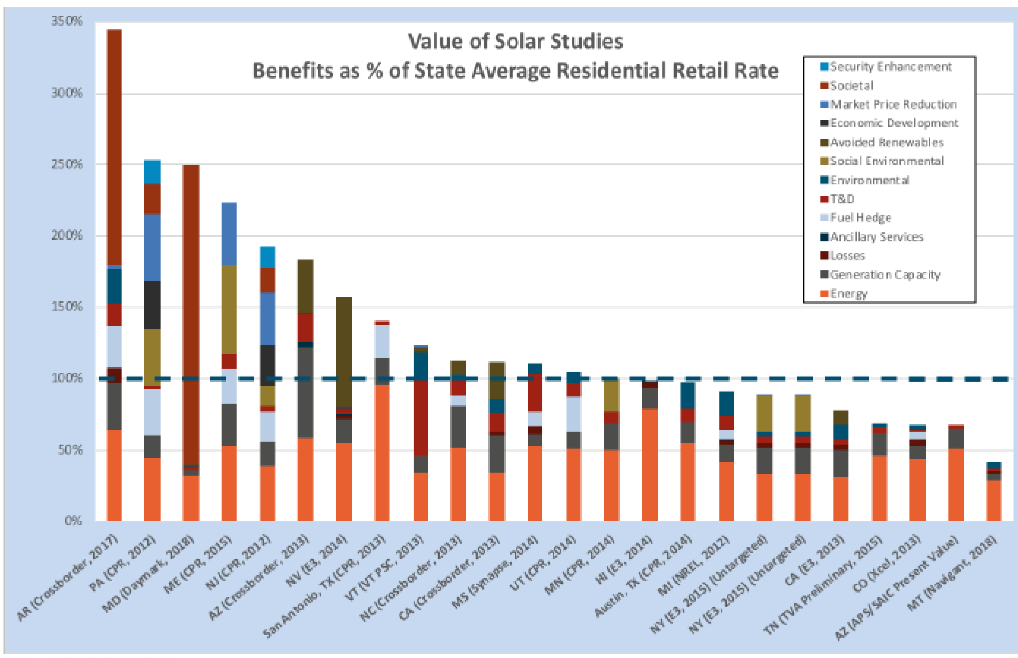
Q. WHAT SORTS OF RESULTS HAVE DG COST-BENEFIT ANALYSES PRODUCED IN OTHER JURISDICTIONS?

A. The results have been quite far-ranging. Figure 1 below depicts the results of numerous past value of solar studies in reference to the residential retail rate in

[5] Act 62, Section 5 (D).

percentage form.[6] As is readily visible in Figure 1, there is a considerable range of results from different studies, driven to a large degree on which potential values are included in the scope of the analysis and accompanying assumptions baked into the studies. The dashed line in the graphic depicts the equivalence point between long-term value and the residential retail rate (*i.e.,* 100%).

Figure 1: Summary of Value of Solar Study Results



Q. HOW DO ECONOMIC IMPACTS OR JOBS CONSIDERATIONS TYPICALLY FIGURE INTO DG COST-BENEFIT ANALYSES?

A. Some, but not all, DG cost benefit analyses focus on the elements of ratemaking itself and therefore do not seek to address economic impacts. Where economic impacts are considered they may be reduced to being considered as a more

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[6] E3 Energy and Environmental Economics. Act 236 Version 2.0. August 7, 2018, *available at*: http://energy.sc.gov/files/Act%20236%20Follow%20Up%20-%20Stakeholder%20Meeting%2008.07.18_Final.pdf

qualitative "societal" benefit as opposed to being translated to a "value rate" denominated in $/kWh. There are a number of reasons why this could be the case, but in general it typically comes down to: (a) such societal benefits are often beyond the scope of cost-effectiveness tests as they are typically conducted (*e.g.*, for energy efficiency cost-effectiveness), (b) modeling macroeconomic effects adds a layer of complexity to the analysis, and (c) some analysts may question how macroeconomic effects should be viewed from the standpoint of comparability in the form of a "rate" against which costs can be compared.

Q. DO ANY OF THE STUDIES SHOWN IN FIGURE 1 STAND OUT WITH RESPECT TO THEIR TREATMENT OF ECONOMIC IMPACTS?

A. Yes. Two studies in particular, one performed by Crossborder Energy (Entergy Arkansas and one performed by Daymark Energy Advisors (Maryland Statewide, individually for each IOU) assign considerable value to societal benefits, including economic impacts. The Arkansas study produced a societal benefit of $33.60/MWh for local economic benefits and a total societal benefit (beyond direct avoided cost savings) of $164/MWh, which includes impacts from other societal benefit streams such as land use, water, and pollution reduction (*i.e.,* beyond any monetized environmental costs).[7]

The Maryland study used a different methodology for quantifying economic benefits. The associated graphic in Figure 1 shows single-year non-levelized

[7] Arkansas Public Service Commission. Docket No. 16-027-R. Joint Report and Recommendations of the Net-Metering Working Group, Attachment A-1. September 15, 2017, *available at*: http://www.apscservices.info/pdf/16/16-027-R_228_1.pdf.

benefits, which for each utility exceeded $200/MWh for behind-the-meter ("BTM") installations. On a 25-year levelized basis, where total monetary benefits are spread over the life of a system and future years discounted, the economic development benefits for systems installed in 2019 (the first year of the study) range from $21/MWh to $29/MWh.[8]

The takeaway from both of these studies is that economic benefits, or conversely, the negative economic consequences of less DG deployment, can be considerable. Their inclusion in a cost-benefit study can easily make the difference between whether or not a "subsidy" is deemed to exist. Furthermore, consideration of economic benefits may also tilt the scale on the relative costs and benefits of BTM generation compared to utility-scale generation, The Maryland study illustrates this, showing economic impact benefits from BTM generation at roughly three times those from utility-scale generation on a $/kWh basis.[9]

Q. WHAT SORTS OF ACTIONS HAVE THE RESULTS OF COST-BENEFIT STUDIES PROMPTED REGULATORS TO MAKE WITH RESPECT TO NET METERING AND DG RATES?

A. It is not always possible to tie the results of a specific study with regulatory actions, or in other cases a lack of action in the part of regulators. In addition, regulators operate within a unique policy context that steers or otherwise influences the

[8] Daymark Energy Advisors. Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland. Appendix C. Prepared for the Maryland Public Service Commission. November 2, 2018. *Available at:* https://webapp.psc.state.md.us/newIntranet/AdminDocket/NewIndex3_VOpenFile.cfm?FilePath=//Coldfusion/AdminDocket/PublicConferences/PC44/145/CostsandBenefitsofSolarAppendices11-2-18.pdf.
[9] *Id.*

actions that they take. South Carolina is no different in this respect, as Act 62 contains unique statements of legislative intent, directs the Commission to take certain specific actions with respect to analyzing costs and benefits of net metering, and grants the Commission discretion to exercise its judgment on consideration of factors outside the specific directives.

Having said all of that, by and large I think it is fair to say that regulators have generally exercised caution when viewing the results of DG value studies or cost of service analyses. This is understandable and reasonable given that future projections will always have some unavoidable uncertainties, and there are inherent limitations with any methodology. Accordingly. the studies are considered informative but not necessarily determinative.

There are two sides to this coin. On one hand, some DG value analyses have produced results indicating that long-term net benefits are well in excess of compensation under net metering, but regulators have not gone ahead with revising DG compensation rates upward in response. For instance, the Maine, Mississippi and Vermont studies represented in Figure 1 did not result in increases in compensation for DG customers, despite results indicating net benefits from DG deployment.

On the other hand, some studies have shown the opposite, but such results did not necessarily spur regulators to adopt those results as a DG compensation rate or otherwise make changes to DG policies and rates. This is the case in Colorado with the 2013 Xcel study, where a subsequent investigation ran from March 2014 to September 2015 and produced a decision declining to make any changes to the existing net metering rules.[10] Since that time Colorado has not undertaken any further action with respect to net metering or DG rates and rate design. To date, Minnesota and New York are the only states that have adopted a DG value framework and deployed it for ratesetting purposes, and in both cases the framework is applicable almost exclusively to community solar systems.

Q. HOW THEN SHOULD THE COMMISSION VIEW NET METERING COST BENEFIT ANALYSES PRESENTED IN THIS PROCEEDING?

A. The Commission should consider all analyses informative and useful, but with an acknowledgement that there is inherent imprecision and uncertainty with any analysis. However, that acknowledgement should not cause the Commission to conclude that a lack of precision or certainty with respect to a benefit category indicates a lack of value. This attitude should be applied equally to results that utilize a limited or narrow framework as well as those that involve projections that the Commission might consider to be somewhat speculative. For instance, cost of service studies may present the illusion of precision, but in practice a cost of service analysis is based on many assumptions and approximations, and by its very nature does not seek to represent future conditions or project a long-term outlook.

Furthermore, I recommend that the Commission consider how costs and benefits are modified with the use of new technologies such as battery storage and smart inverters. Such a forward-looking approach to DG value is appropriate given

[10] Colorado Public Utilities Commission. Docket No 14M-0235E. Decision Closing Proceeding dated September 15, 2015, *available at:* https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=601823

that the Commission's present objective is to establish a basic foundation on which it can rely to develop durable rate options for future DG customers that properly compensate them for the value they provide to the electric system and to ratepayers/society as a whole. Applying this mindset will help ensure that the scope of the analysis properly incorporates consideration of all benefits even if those benefits are assessed as qualitative or un-quantified but nevertheless important.

III. ECONOMIC IMPACTS OF DG POLICY DECISIONS

Q. HOW SHOULD THE COMMISSION VIEW THE EXISTENCE OF MACROECONOMIC IMPACTS AS PART OF ITS EFFORTS TO IDENTIFY THE COSTS AND BENEFITS OF THE NET METERING PROGRAM?

A. Act 62 expressly directs the Commission to consider direct and indirect economic benefits so those benefits must be given due weight in the Commission's analysis. Having said that, while macroeconomic impacts can be quantified, I do not necessarily suggest that those quantified benefits are appropriate to directly translate into a specific rate. In light of both of these factors, economic impacts are best viewed as a "modifier" in relation to the cost benefit results that derive solely from impacts on electricity system costs. That is, even if those impacts are not directly translatable into a "value rate" it is reasonable to allow economic impacts to tip the scale in one direction or another. For instance, if a cost benefit analysis identifies a narrow or moderate net cost gap under retail net metering, it would reasonable to take economic impact considerations into account to counterbalance the cost gap, even if the economic impacts are not able to be quantified with 100% certainty.

Furthermore, since the Commission is engaging in an effort to define net metering costs and benefits as a precursor to consideration of changes to DG rates, it is also important to consider the economic impacts from the perspective of potential long-term macroeconomic losses should new DG rates cause the industry to contract. This is to say that measuring the economic impact of the DG industry in South Carolina up the present reflects past growth rather than future potential growth. To the extent that beneficial economic impacts exceed any demonstrated cost-shift impacts on a $/MW basis, the benefits will grow over time at a greater rate than costs. For instance, consider a hypothetical scenario where one MW of new DG produces a cost-shift of $1 million over the life of the systems, but is accompanied by $5 million in economic benefits. Across one MW, the difference in costs and benefits is relatively small ($4 million). On a larger scale, such as across 200 MW, the costs are significantly larger ($200 million), but the scale of benefits is larger by a higher amount ($1 billion). I discuss some specific examples of the impacts of DG policy decisions later in my testimony.

Q. HOW DO COST SAVINGS FOR DG CUSTOMERS FIGURE INTO ECONOMIC BENEFITS FROM DERS?

A. There are two ways. First, assuming net savings on electricity costs, a DER customer has additional money to save or spend on other things. Either way, that cost savings contributes back to the overall economy in the form of spending on other goods and services at some point in the future.

Second, the prospect for energy cost savings is generally considered to be a primary driver that motivates DER investments in the first place. There are certainly some customers that have other reasons for making the decision to install a DER, and for some of whom cost savings are not necessarily the most significant motivating factor. That said, for almost all customers cost savings will be a factor, and for many it is a highly significant factor. This is especially true for moderate to lower income customers who have less disposable income and high energy burdens.

For instance, a 2018 analysis of income trends among solar PV adopters by Lawrence Berkeley National Lab showed a pattern of greater adoption of PV over time among low-moderate income ("LMI") customers, coupled with a greater prevalence of third-party ownership among LMI customers than residential PV customers as a whole. The authors attribute these characteristics to PV cost declines over time coupled with greater cash constraints and the ability of LMI customers to monetize tax credits.[11] Both characteristics speak to the relative role that energy cost savings plays with LMI PV customers relative to PV adopters more generally.

In other words, the prospect for cost savings, especially immediate cost savings, broadens the potential DER customer base. The size of that potential customer base and the number of installations it can support has a direct relationship to the size of the workforce necessary to meet that demand. Simply put, more

[11] Barbose et al. Income Trends of Residential PV Adopters An analysis of household-level income estimates. April 2018, *available at*: https://eta-publications.lbl.gov/sites/default/files/income_trends_of_residential_pv_adopters_final_0.pdf

potential customers results in a greater number of DG installations, which in turn produces more economic activity and more jobs.

Q. CAN YOU PROVIDE ANY SPECIFIC EXAMPLES OF HOW CHANGES TO DER POLICIES AND COMPENSATION RATES HAVE AFFECTED INSTALLATION RATES AND THE SOLAR INDUSTRY GENERALLY?

A. Yes. Two of the most prominent examples of regulatory decisions that had significant negative economic consequences are those made by the Salt River Project ("SRP") in Arizona and the Nevada Public Utilities Commission ("PUCN"). In both instances, dramatic changes to DER rates produced dramatic declines in installation rates that were accompanied by rapid contraction of the solar industry and significant job losses.

Q. PLEASE ELABORATE ON THE DECISION MADE BY SRP AND THE CONSEQUENCES IT HAD FOR THE ARIZONA SOLAR INDUSTRY.

A. In a February 2015 decision, SRP adopted a policy that subjected all new residential DER customers with interconnection applications submitted after December 8, 2014 to demand rates. The decision grandfathered customers with existing interconnection applications and allowed those customers one year to complete the installation of a grandfathered system. Figure 2 below shows residential installation rates in SRP territory compared to rates in Arizona Public Service ("APS") territory from 2013 through 2019 based on U.S. Energy Information Agency ("EIA") monthly data on residential net metered capacity. Table 1 illustrates the annual growth rate alongside the amount of capacity installed in each utility territory each year.

Figure 2 and Table 1 show that prior to the SRP decision, residential NEM capacity was growing at a rate roughly comparable to APS. A clear inflection point is visible during the last half of 2015, followed by minimal growth in installations during 2016 and 2017 and a slow pick up in installation activity thereafter. The timing of the decision relative to the slowing of the growth shows a lag as legacy grandfathered installations make their way into the installed capacity numbers during the first half of 2015. After July 2015 growth slows considerably and persists through 2019, most notably during 2016 and 2017. To look at it another way, the individual years of 2014 and 2015 produced significantly more residential solar NEM installations individually than the entire 2016 – 2018 period following the dramatic rate changes for DER customers.

Figure 2: Arizona Monthly Residential NEM Capacity (MW)

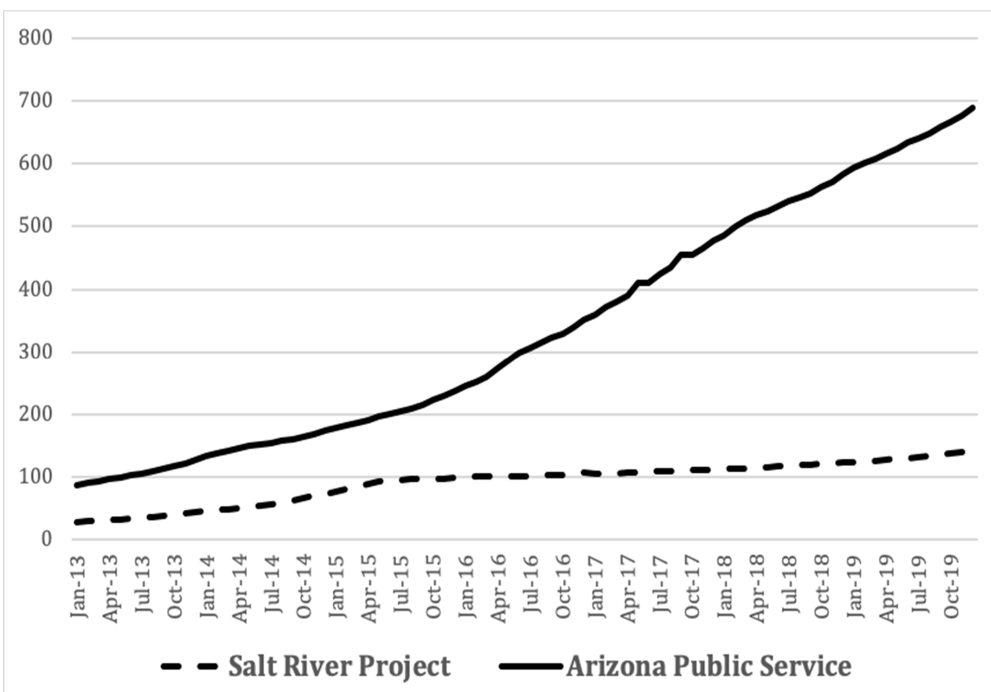

Table 1: Arizona Residential NEM Growth

Year	SRP Capacity Added (MW)	APS Capacity Added (MW)	SRP Growth Rate (%)	APS Growth Rate (%)
2013	16.0	39.7	4.23%	3.46%
2014	29.0	47.5	4.34%	2.68%
2015	26.5	63.0	2.62%	2.60%
2016	8.7	113.6	0.70%	3.31%
2017	3.7	126.8	0.28%	2.60%
2018	11.0	105.9	0.79%	1.68%
2019	18.4	104.3	1.17%	1.38%

Q. BEYOND THE DIFFERENCES BETWEEN SRP AND APS, WHAT ELSE DO FIGURE 2 AND TABLE 1 SHOW?

A. Table 1 also illustrates the impact of the imposition of a new compensation and retail rate regime for residential solar DG customers of APS, which took effect September 1, 2017. The new compensation regime, called the Resource Comparison Proxy Export Rate ("RCP Rate"), provides customers with compensation for exports at less than the retail rate. Under the RCP Rate design export compensation has fallen from roughly 12.9 cents/kWh for the September 1, 2017 – August 30, 2018 period to the current rate of 10.45 cents/kWh applicable for new DG customer enrollments from September 1, 2019 to August 30, 2020. New residential solar DG customers are also subject to mandatory time-of-use ("TOU") rates and a monthly grid access charge unless they take service under a rate with demand charges.

Subsequent to these changes the growth, rate for new residential solar DG installations has slowed considerably, from 2.6% in 2017 to 1.68% in 2018 and

1.38% in 2019. However, the Arizona Corporation Commission ("ACC") recently voted to maintain the September 2019 – August 2020 rate through October 1, 2021 rather than make the typical annual reduction to the rate in special consideration of the unique economic disruptions caused by COVID-19.[12]

Q. HOW DID THE CHANGES IN DG POLICIES AND RATES AFFECT SOLAR JOBS IN ARIZONA?

A. SolarCity reportedly relocated 85 of its 800 Arizona workers out of state.[13] In addition The Solar Foundation's Solar Jobs Census 2015 reported a decline of 2,278 solar jobs from 2014 to 2015, a 24.8% decline.[14] While it is not possible to trace all of this decline to a reduction in residential solar installations in SRP territory, the DG policy changes almost certainly played a role.

Q. PLEASE ELABORATE ON THE DECISION MADE BY THE PUCN AND ITS CONSEQUENCES ON THE NEVADA SOLAR INDUSTRY.

A. In February 2016 the PUCN adopted far-reaching changes to DG rates and compensation regimes. The new rate regime was initially applied to all existing and new net metering customers over a 12-year phase-in period. Ultimately, the transition process would have resulted in the fixed customer charge rising to $38.51 by 2028 with the credit for excess generation reduced to roughly 26% of the projected retail rate for Nevada Power Company ("NPC") residential DG

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[12] ACC. News Release. October 1, 2020, *available at*: https://azcc.gov/news/2020/10/01/commissioner-lea-m%C3%A1rquez-peterson-leads-second-chance-for-az-homeowners-to-install-new-rooftop-solar-in-2020-2021-provides-one-more-year-at-current-export-rate

[13] Bobby Magill. Climate Central. New Fees Seen to Weaken Demand For Rooftop Solar. November 10, 2015, *available at:* https://www.climatecentral.org/news/new-fees-weaken-rooftop-solar-demand-19667

[14] The Solar Foundation. Solar Jobs Census, *available at*: https://www.solarstates.org/

customers. For the Sierra Pacific Power Company ("SPPC") the monthly fixed charge was slated to eventually rise to $44.43 by 2028, with the credit for excess generation reduced to roughly 45% of the projected retail rate.[15] In a subsequent September 2016 decision the PUCN allowed for grandfathering for customers with pending net metering applications as of December 31, 2015, permitting them to opt-in to grandfathered net metering by February 15, 2017.[16] In response to widespread dissatisfaction with the PUCN's net metering policy changes, the legislature passed and the Governor signed A.B. 405 in June 2017. A.B. 405 effectively reinstated net metering without additional charges and instituted a modest step-down in the monthly carryover rate for excess generation.[17]

The disruption in residential solar sector caused by the PUCN's February 2016 decision and the rebound associated with A.B. 405, are readily visible in Figure 3 and Table 2. Note that numbers for SPPC are shown relative to the secondary Y-Axis located on the right side of Figure 3 while values for NPC are shown on the primary Y-Axis located on the left side.

[15] PUCN. Docket Nos. 15-07041 and 15-07042. Modified Final Order dated February 12, 2016, *available* at; http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2015-7/9692.pdf
[16] PUCN. Docket Nos. 16-07028 and 15-07029. Order dated September 16, 2016, *available at*: http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2016-7/15119.pdf
[17] Nevada Legislature. A.B. 405, enacted June 15, 2017, *available at*: https://www.leg.state.nv.us/Session/79th2017/Reports/history.cfm?BillName=AB405

Figure 3: Nevada Residential NEM Capacity (MW)

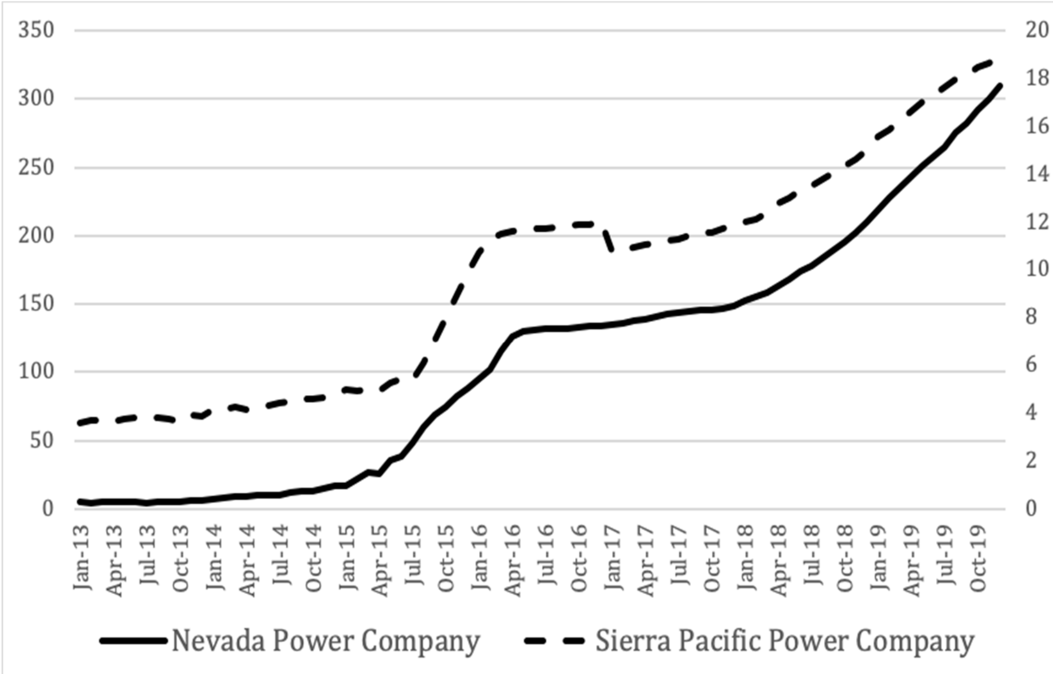

Table 2: Nevada Residential NEM Growth

Year	NPC Capacity Added (MW)	SPPC Capacity Added (MW)	NPC Growth Rate (%)	SPPC Growth Rate (%)
2013	1.0	0.3	1.81%	0.61%
2014	11.5	0.9	9.55%	1.81%
2015	70.4	5.1	14.48%	6.27%
2016	46.7	2.2	3.62%	1.65%
2017	14.6	-0.2	0.87%	-0.13%
2018	61.0	3.2	2.90%	1.99%
2019	99.5	3.9	3.29%	1.94%

Figure 2 shows the "cliff" in new installations that takes hold at the end of the first quarter of 2016. A second cliff reflected in the SPPC numbers shows customers that had pending applications at end the 2015 electing not to move forward, causing them to fall out of the NEM capacity numbers in early 2017. The enactment of A.B. 405 is reflected in the resurgence of new residential net metering installations beginning in late 2017 and early 2018, after the PUCN finalized A.B. 405 net metering rules in September 2017.

Q. HOW DID THE FEBRUARY 2016 PUCN DECISION AFFECT SOLAR JOBS IN NEVADA?

A. The Solar Foundation's Solar Jobs Census shows solar installation jobs declining by 2,687 jobs in 2016 and then declining further in 2017 by another 1,395 jobs – a decline from 8,285 jobs in 2015 down to 4,203 in 2017 for a total of 4,082 job losses in two years. Figures from 2018 and 2019 reverse the downward trend, with 1,048 solar installation jobs reported as being added in 2018, and 323 jobs added in 2019 (for a total of 5,574 solar installation jobs).[18] While the rooftop industry has recovered somewhat from the substantial job losses following the PUCN's 2016 decision, the most recent jobs numbers indicate that the recovery has still not completely erased the losses from 2016 and 2017.

IV. GRID RESILIENCY BENEFITS

Q. HOW WOULD YOU DEFINE THE TERM "RESILIENCE" IN THE CONTEXT OF THE ELECTRIC SYSTEM?

A. I do not know that there is a single completely agreed-upon definition. Presidential Policy Directive 21 defined resilience within the general context of critical infrastructure as "the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring

[18] The Solar Foundation. Solar Jobs Census, *available at*: https://www.solarstates.org/

threats or incidents."[19] One alternative definition I am aware of (though there are certainly others) attempts to put a finer point on the topic by excluding *reliability* and *recovery* from the scope, as follows: "Grid resilience is the ability to avoid or withstand grid stress events without suffering operational compromise or to adapt to and compensate for the resultant strains so as to minimize compromise via graceful degradation. It is in large part about what does not happen to the grid or electricity. [20] For the present purpose, in my view the key features of both definitions are the dual ideas of lower vulnerability and adaptability to changing conditions, including potentially significant disruptive events (*i.e.,* avoid and withstand grid stress).

Q. HOW CAN DERS ENHANCE GRID RESILIENCY?

A. There are at least two aspects of the concept of resiliency that merit some discussion. The first relates to resource diversity - or "don't put all your eggs in one basket." From the standpoint of resource adequacy, a collection of DERs is less prone to catastrophic failure than an equivalent amount of capacity provided by a single unit. If one assumes a standard failure rate, the probability of full outage of the DER resource at any given time declines at a geometric rate with each additional facility. For instance, the California Independent System Operator ("CAISO") reports that one contributing factor to the power outages experienced during mid-

[19] Presidential Policy Directive 21. Critical Infrastructure Security and Resilience. February 12, 2013, *available at*: https://obamawhitehouse.archives.gov/the-press-office/2013/02/12/presidential-policy-directive-critical-infrastructure-security-and-resil

[20] JD Taft. Pacific Northwest National Lab. Electric Grid Resilience and Reliability for Grid Architecture. March 2018, p. 3, *available at*: https://gridarchitecture.pnnl.gov/media/advanced/Electric_Grid_Resilience_and_Reliability_v4.pdf

August 2020 in California was 1,400 – 2,000 MW of forced outages among the state's natural gas fleet "largely attributed to extreme heat".[21]

While catastrophic failures are infrequent, and in most cases can be handled, they can be highly impactful when they are coincident with other sources of stress on the system. The potential for catastrophic failure is not confined to generation units specifically. The loss of transmission facilities could contribute to a similar outcome where generation is available, but cannot be transmitted to load. Dispersed DERs can help mitigate that potential as well.

The second aspect is oriented more around individuals and communities. In the face of widespread outages, such as might be caused by a hurricane or other extreme weather events that impact the distribution system, locations with access to non-grid power can help individuals and communities "weather the storm" during the event and in the days and weeks following while grid outages continue to impact critical facilities and other infrastructure. This could take the form of community centers or other common areas that offer critical services, such as air conditioning, electricity for medically necessary devices, refrigeration of medicines, and essential communications. It could also take the simpler form of neighbors helping out neighbors. Localized generation that remains on-line for emergency purposes, especially when equipped with on-site storage, is highly valuable under circumstances where outages are widespread and prolonged.

[21] CAISO. Preliminary Root Cause Analysis – Mid-August 2020 Heat Storm. October 6, 2020, p. 8, *available at*: http://www.caiso.com/Documents/Preliminary-Root-Cause-Analysis-Rotating-Outages-August-2020.pdf

Q. HAVE THE RESILIENCY BENEFITS OF DERS BEEN RELIABLY QUANTIFIED?

A. Not really. Most cost-benefit analyses acknowledge that DERs produce resiliency benefits but thus far there are not any generally accepted metrics for the concept, or methodologies for translating those metrics into monetary amounts. To be clear, there are standard metrics for reliability, such as the CAIFI and SAIFI and CAIDI and SAIDI indexes,[22] and it is possible to generate estimates of the monetary cost of outages in terms of lost economic output, wasted goods and services (e.g., spoiled food), etc., but various competing methodologies exist and each has its own limitations. The National Association of Regulatory Utility Commissioners ("NARUC") has published an extended discussion of analytical practices and their pros and cons, which acknowledges that "while it is clear DERs offer resilience benefits, it is unclear how to determine the value of those benefits."[23]

Ultimately, it is difficult to capture the full scope of potential economic losses, or the unvalued toll that disruptions can have at a personal level on individuals. There are simply a lot of factors involved, such as the length of the outage, timing, and personal or business circumstances. What constitutes a minor inconvenience for one customer can be highly impactful for another.

[22] CAIFI and SAIFI relate the outage frequency while CAIDI and SAIDI to outage duration.
[23] Converge Strategies LLC The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices. Prepared for NARUC. April 2019, p. 4, *available at*: https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198

Q. HOW DOES GRID RESILIENCY AS A BENEFIT OF DG TIE INTO THE AN ANALYSIS OF THE COSTS AND BENEFITS OF NET METERING?

A. There are two factors involved here. First, most net metering systems today provide enhanced resiliency only in the form of a more diversified energy and capacity resource, but as DG systems become increasingly paired with battery storage, the potential for DG to contribute to resiliency to a much greater degree will increase. Second, the installation of energy storage can occur as: (a) part of a retrofit to an existing DG system, or (b) a feature of a newly installed DG system. In the near future, it is likely that many DG systems will not be installed initially with energy storage. Nevertheless, an existing DG system without energy storage still provides a foundation onto which energy storage can be more easily layered in the future. That foundation is supported by the basic DG compensation framework, which motivates the installation of DG in the first place. Without a framework that provides a solid value proposition, there will be fewer potential candidates for the addition of energy storage as a retrofit. The question of whether energy storage is installed hinges on the value-added proposition, which applies equally to storage retrofits or new systems installed with co-located energy storage at the outset.

Q. WHY IS IT REASONABLE TO EXPECT THAT THE INCREASED PREVALANCE OF CUSTOMER-SITED ENERGY STORAGE WILL BE TIED TO THE PREVALANCE OF DG MORE GENERALLY?

A. There are three reasons. First, federal tax credits for customer-sited renewables can be applied to costs associated with on-site energy storage, but only if the energy storage is charged primarily from a qualifying renewable energy device. Second, on-site DG and co-located energy storage can share some of the same equipment (*e.g.,* the inverter), which produces lower incremental net costs for an energy storage system co-located with a DG system than if the energy storage was installed on a standalone basis. Third, customers value resiliency; and in particular customers who reside in areas subject to natural disasters that have a high potential to result in electrical outages (*e.g.,* hurricanes) are likely to place value on having access to back-up power. The potential for access to back-up power is one factor motivating customers to become interested in installing a DER in the first place, to the point where the question "Will my solar system provide me with power during an outage?" is commonly included in consumer fact sheets and FAQ resources. In other words, customers with an interest in installing a solar system are likely to also be pre-disposed to at least consider the installation of storage as well.

Customer-sited DG co-located with storage provides enhanced resiliency benefits over storage or DG sited independently of each other. As storage costs decline and market participation pathways emerge to allow customers with storage to earn revenues in exchange for providing grid services, the incentive for customers to retrofit existing DG systems with storage will increase.

Q. IS IT YOUR EXPECTATION THAT CUSTOMERS WILL RETROFIT DG SYSTEMS TO INCLUDE ENERGY STORAGE?

A. Yes. While it is difficult to predict with what frequency storage retrofits may occur, at least some DG customers will seek to retrofit their systems to include energy storage for the reasons described above. Retrofits can be pursued at any time, but are likely to be most cost-effective if they take place at a time when the inverter is being replaced as well. That might occur about midway through the average life of the DG system (*e.g.,* 10 – 15 years) or if the system is undergoing other retrofits, such as an expansion to accommodate additional on-site load (*e.g.*, an electric vehicle). Again, the prevalence of storage retrofits is likely to be tied, though not exclusively so, to the financial upside, which in turn depends on the market participation pathways available to unlock both the customer and the broader system / grid and value that energy storage systems can provide.[24]

Q. HOW DOES THE POTENTIAL FOR STORAGE RETROFITS RELATE BACK TO THE COMMISSION'S EVALUATION OF THE COSTS AND BENEFITS OF NET METERING?

A. As I previously discussed, the cost-benefit analysis should consider what the value of DG *could be* with the right policy framework, not just what it is under the current policy framework. The potential for retrofits figures into this because over the time horizon of a long-term study some number of systems will be retrofitted with storage and net metering created the potential for those retrofits to occur.

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION ON THE COMPANY'S APPLICATION.

A. On the issue of the general nature of the analysis of costs and benefits, I recommend that the Commission take a broad and forward-looking view when determining the

[24] As with DG more generally, some customers derive non-financial or otherwise difficult to quantify benefits from installing on-site energy storage, most specifically access to back-up power during outages.

scope of potential benefits to be included in the evaluation of the benefits and costs of net metering. Pursuant to this approach:

- The scope of benefits should include all benefits reasonably expected to arise from DG growth even if those benefits are difficult to quantify or have associated uncertainty.
- Qualitative benefits should still be given weight in the assessment of the costs and benefits of net metering.
- The Commission should consider the ways in which new technologies such as on-site energy storage and smart inverters could modify the results of the analysis.

Such an outlook is reasonable because the Commission is engaged in an exercise of evaluating future DG rates and rate structures and with proper signals and mechanisms, these new technologies can dramatically enhance DG value.

With respect to the issue of direct and indirect economic impacts, I recommend that the Commission give substantial weight to the potential negative economic impacts of utilizing a narrow scope of benefits to determine DG value and utilizing that value in setting DG rates. Such substantial weight is supported by the express directive in Act 62 that the evaluation of costs and benefits include direct and indirect economic impacts, and statements of legislative intent that speak to avoiding disruption of a growing DG market, and building on the success of Act 236 of 2014.

Finally, with respect to the value of DG in enhancing grid resiliency, I recommend that the Commission at minimum incorporate enhanced grid resiliency as a qualitative benefit if it determines that it cannot be reliably quantified. I urge the Commission to adopt a forward-looking approach to evaluating this future benefit stream, and incorporate the acknowledgement that net metering itself contributes to greater resiliency by supporting the installation of existing DG systems that can later be retrofitted with battery storage. In this respect, I urge the Commission to view the benefits of net metering and DG as they *could be* with the right policies, not just what they have been in the past.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.